

Omnibus of common quality Code amendments

Decision paper

23/10/2026



Executive summary

The Electricity Authority Te Mana Hiko (Authority) is committed to promoting the security and resilience of New Zealand's power system in a highly electrified future, ensuring it is set up to deliver the best possible outcomes for consumers. As the sector evolves, it is critical that we, as a regulator, anticipate challenges and enable a smooth transition to a more electrified economy.

Through our multi-year Future Security and Resilience (FSR) work programme,¹ we are enabling new and evolving technologies, and addressing security and resilience risks. These changes will help ensure we have a power system that is reliable, flexible and future focused.

The highest priority activity in the FSR programme is reviewing the common quality requirements in Part 8 of the Electricity Industry Participation Code 2010 (Code). The review's purpose is to ensure these requirements enable evolving technologies, particularly inverter-based resources, such as wind generation, solar photovoltaic generation and battery energy storage systems, in a manner that is consistent with the Authority's statutory objectives.

The review of the common quality requirements consists of several sub-projects that progress issues related to frequency, voltage, harmonics, information requirements, and Code terminology.² In late 2024 and early 2025 the Authority progressed a first omnibus of common quality-related Code amendments, which came into effect on 1 May 2025.³ This paper sets out our decision on a second omnibus of common quality-related Code amendments.

We sought feedback on six proposed Code amendments

In March 2026, the Authority consulted on six proposals to amend the Code – covering various common quality requirements in Parts 1, 7 and 8 of the Code. These Code amendments were:

- FSR-101: Align over-frequency limits between the Code and the Policy Statement – a document incorporated by reference in Part 8 of the Code
- FSR-102: Clarify requirements for voltage control systems and connection transformers
- FSR-103: Amend the 'fast instantaneous reserve' and 'sustained instantaneous reserve' definitions in Part 1 of the Code
- FSR-104: Revise two fault ride through exclusions
- FSR-105: Clarify who provides information to assess compliance with fault ride through obligations
- FSR-106: Clarify obligations related to frequency management and frequency support.

We received five submissions on the proposed Code amendments. The submissions and consultation paper are available on the Authority's website.⁴ We thank submitters for taking the time to share their views on the proposals.

We have decided to proceed with all six proposals with some changes to three of them

The Authority has considered all feedback and has decided to proceed with the six Code amendments. However, we have made some changes to three Code amendments—FSR-101, FSR-103 and FSR-106—in response to submitter feedback:

- FSR-101 – we have adopted a 60-second over-frequency recovery threshold of—
 - 50.75Hz for North Island and South Island contingent events

¹ [Future security and resilience programme](#)

² See our consultation paper [Review of common quality requirements in Part 8 of the Code – Issues paper, April 2023](#)

³ [Part 8 Code terminology and network information – Decision paper, April 2025](#)

⁴ [Electricity Authority | Our projects | Our consultations | Parts 1, 7 and 8 Common quality requirements review](#)

- 51.2Hz for North Island extended contingent events
- 52Hz for South Island extended contingent events.
- FSR-103 – we have amended the fast instantaneous reserve and sustained instantaneous reserve definitions to clarify that they relate to contingent events or extended contingent events that cause a fall in frequency.
- FSR-106 – the variability and intermittency of intermittent generation is taken into account when requiring assets to support frequency management during under-frequency events.

The six Code amendments will help to maintain the security and resilience of the power system. They will also make the Code more consistent and better enable it to accommodate evolving technologies, particularly inverter-based resources such as wind generation, solar photovoltaic generation and battery energy storage systems. We expect this to keep downward pressure on consumers' power bills and give consumers greater choice and flexibility in how they use and supply electricity, ultimately delivering long-term benefits to them.

Next steps

The Code amendments will come into effect on 1 December 2026.

The Procurement Plan updates required under the FSR-103 Code amendment will come into effect before the FSR-103 Code amendment. In accordance with clause 7.20(5) of the Code, the System Operator is not consulting on these changes to the Procurement Plan as the Authority has consulted sufficiently on this matter.

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1 Purpose

- 1.1 This paper sets out the Electricity Authority Te Mana Hiko (Authority) decision to amend the Electricity Industry Participation Code 2010 (Code) to give effect to the six Code amendments described in this decision paper.
- 1.2 These six Code amendments address issues relating to Code terminology and clarify various common quality obligations in Parts 1, 7 and 8 of the Code.
- 1.3 This paper:
 - (a) explains the final Code amendments, including where these diverge from the Code amendments proposed in [our March 2026 consultation paper](#)
 - (b) sets out our responses to issues raised in feedback on the consultation paper
 - (c) sets out how the Code amendments are consistent with our statutory objectives
 - (d) outlines next steps.

2 Background to the Omnibus of common quality Code amendment proposals

- 2.1 New Zealand's power system is undergoing a significant transformation. As the economy becomes more electrified, maintaining power system resilience will become more challenging – for example, managing peak demand fluctuations and increasing variability and intermittency of energy sources.
- 2.2 The Authority considers evolving technologies, particularly inverter-based resources, to be a key enabler of electrification. Examples of inverter-based resources include wind generation, solar photovoltaic generation, and battery energy storage systems (BESSs). These technologies will enable consumers to have more choice and flexibility around their electricity use and supply.
- 2.3 The Authority's Future Security and Resilience (FSR) work programme is one of several initiatives supporting the electrification of New Zealand's economy. The FSR programme seeks to ensure New Zealand's power system remains secure and resilient as the country transitions towards a lower emissions economy.
- 2.4 The highest priority activity in the FSR work programme is a review of common quality⁵ requirements in Part 8 of the Code. Common quality requirements are becoming increasingly important as the power system evolves from one dominated by a small number of large, synchronous generating stations to a more distributed system comprised of many smaller, inverter-based, intermittent and variable resources.
- 2.5 The Authority has adopted an iterative and phased approach to reforming the Part 8 common quality requirements. The changes we are making are intended to ensure that common quality requirements support new and evolving technologies, while addressing security and resilience risks posed by these technologies and increased electrification.

⁵ Common quality means those elements of the quality of electricity conveyed across New Zealand's power system that cannot be technically or commercially isolated to an identifiable person or group of persons. An example is the frequency of electricity.

3 The Authority has finalised the six Code amendments after considering submissions

3.1 The Authority received five submissions on our March 2026 consultation paper, from:

- (a) the Electricity Engineers' Association (EEA)
- (b) Nova Energy
- (c) Transpower New Zealand
- (d) the University of Auckland
- (e) WEL Networks.

3.2 This document summarises and responds to submitter feedback on each of the six Code amendment proposals that we consulted on. The full submissions are available on the Authority's website.⁶

3.3 The Authority has decided to proceed with all six proposals:

Code amendment	Page number
FSR-101: Align over-frequency limits between the Code and the Policy Statement	7
FSR-102: Clarify requirements for voltage control systems and connection transformers	9
FSR-103: Amend the 'fast instantaneous reserve' and 'sustained instantaneous reserve' definitions	10
FSR-104: Revise two fault ride through exclusions	13
FSR-105: Clarify who provides information to assess compliance with fault ride through obligations	14
FSR-106: Clarify obligations related to frequency management and frequency support	15

3.4 All submitters supported the policy intent of the Code amendment proposals, noting that the amendments will address genuine issues and will improve the clarity, consistency, and operation of the Code. There was also broad agreement with each proposal's regulatory statement, with some suggested minor improvements put forward for the regulatory analysis for the FSR-101 and FSR-103 proposals.

3.5 We have made some changes to three Code amendment proposals in response to the feedback received. More details are set out below.

3.6 These Code amendments will come into effect on 1 December 2026. The updated Procurement Plan required under FSR-103 will come into effect prior to the FSR-103 Code amendment. Details of the amended Procurement Plan can be found [here](#).

FSR-101: Align over-frequency limits between the Code and the Policy Statement

Proposal

3.7 The Authority proposed to re-insert in Part 7 a principal performance obligation for the System Operator to ensure frequency does not exceed 52 Hertz in the North Island or 55 Hertz in the South Island (during a contingent event and an extended contingent event).

3.8 We proposed removing the definitions, 'maximum South Island frequency' and 'over frequency limit', from Part 1 of the Code. While 'maximum South Island frequency' is defined

⁶ [Submissions and consultation paper for the Omnibus of common quality Code amendment proposals](#)

in Part 1, it is not referenced in any other part of the Code. We proposed the definition be removed from Part 1 of the Code and instead described in the principal performance obligations on the System Operator, which are set out in Part 7 of the Code. The defined term 'over frequency limit' is used only once in the Code – in clause 9 of Technical Code B of Schedule 8.3. We proposed inserting the meaning of 'over frequency limit', which is "the maximum frequency of 50.5 Hz", directly into the operative clause to improve the readability of this clause.

Stakeholder feedback

- 3.9 All stakeholders supported this proposal and agreed with the regulatory statement.
- 3.10 The University of Auckland's feedback included that the technical details in the regulatory statement could be clarified further. Specifically, the Authority should provide further technical justification for proposing 51.25Hz as the threshold to which the System Operator needed to return North Island frequency within 60 seconds of a contingent or extended contingent event that caused over frequency in the North Island.
- 3.11 The University of Auckland further submitted that if important frequency standard definitions are moved out of Part 1, the impact on transparency should be considered. This was on the basis that Part 1 usually would be the first section of the Code that non-specialists read, including the owners of generating stations connected to a distribution network.

The Authority's decision

- 3.12 After considering submitter feedback, the Authority has decided to amend the proposed 60-second over-frequency recovery threshold for North Island and South Island contingent and extended contingent events.
- 3.13 The Authority notes the reason we proposed 51.25Hz as the 60-second over-frequency recovery threshold for North Island contingent events and extended contingent events was for consistency with the pre-May 2016 threshold at which the System Operator limited over-frequency momentary fluctuations to seven in any 12-month period.⁷
- 3.14 However, after further consideration we have decided to adopt the following 60-second over-frequency recovery thresholds:
 - (a) 50.75Hz for North Island and South Island contingent events
 - (b) 51.2Hz for North Island extended contingent events
 - (c) 52Hz for South Island extended contingent events.
- 3.15 The basis for this decision is as follows:
 - (a) a 60-second over-frequency recovery threshold of 50.75Hz for North Island and South Island contingent events aligns with the threshold in the Policy Statement⁸
 - (b) 60-second over-frequency recovery thresholds of 51.2Hz for North Island extended contingent events and 52Hz for South Island extended contingent events are supported by simulations undertaken by the System Operator for each of the following scenarios:
 - (i) a bi-pole trip of the HVDC link when there is high energy transfer across the link and low generation in the receiving island

⁷ Former clause 7.2(1)(b)(iii) of the Code.

⁸ See paragraph 17.1.5 of the Policy Statement, which requires the System Operator to restore frequency in the North Island and South Island to within 50Hz $\pm$ 0.75Hz within 60 seconds following a contingent event.

(ii) a loss of all of the Tiwai Point aluminium smelter load (similar to a loss of a large quantity of data centre load)

(iii) partial activation of automatic under-frequency load shedding.

- 3.16 The System Operator's simulations for each of these scenarios show the system frequency recovering within 60 seconds to below 51.2Hz in the North Island and to below 52Hz in the South Island. This indicates these thresholds can be met without the System Operator needing to procure additional over-frequency reserve or introduce constraints in the market dispatch system.
- 3.17 Further to the University of Auckland's other feedback, the Authority considers that removing the definition of 'over frequency limit' will reduce the potential for readers of the Code to confuse this term with maximum frequency, particularly when 'over frequency limit' is not read in conjunction with the operative clause where it is used (clause 9 of Technical Code B of Schedule 8.3 of the Code). With the meaning of the definition included in the one operative clause in which it is used, there is no reason to retain the definition in Part 1 of the Code.

FSR-102: Clarify requirements for voltage control systems and connection transformers

Proposal

- 3.18 The Authority proposed to amend clause 5 of Technical Code A of Schedule 8.3 of the Code to clarify that a connection transformer is required at the connection point between the transmission grid and a generating station or generating unit.

Stakeholder feedback

- 3.19 All stakeholders supported this proposal and agreed with the regulatory statement as the clarification aligns with modern plant design and improves connection efficiency.
- 3.20 The University of Auckland submitted that:
- (a) An explicit requirement that station-level voltage control systems coordinate unit-level reactive power dispatch should be included in the Code drafting.
 - (b) The Authority should clarify the application of the (clause 5(2)(b)(i)) words "at least one connection transformer" to split bus and distributed point of connection architectures.

The Authority's decision

- 3.21 After considering submissions, the Authority has decided to proceed with the proposal as consulted on.
- 3.22 In response to the University of Auckland's feedback, the Authority notes that the obligation for reactive power dispatch is at the station level. Therefore, we consider there is no need to explicitly require that station-level voltage control systems regulate unit-level reactive power dispatch.
- 3.23 The Authority also considers the words "at least one connection transformer, located at the generating station's point of connection on the grid or between the generating station's point of connection on the grid and the generating units," in clause 5(2)(b)(i) of Technical Code A of Schedule 8.3 adequately provide for either one or more than one connection transformer to be in place under a split bus or distributed point of connection architecture. Accordingly, we have not made any changes to the Code drafting.

FSR-103: Amend the ‘fast instantaneous reserve’ and ‘sustained instantaneous reserve’ definitions

Proposal

- 3.24 The Authority proposed amending the definitions of ‘fast instantaneous reserve’ (FIR) and ‘sustained instantaneous reserve’ (SIR) in Part 1 of the Code, to refer to the definitions in the Procurement Plan.
- 3.25 These changes would require an update to the Procurement Plan to specify the performance requirements for FIR and SIR provided by generation and BESSs.

Stakeholder feedback

- 3.26 There was broad support for amending the FIR and SIR definitions, and general agreement with the proposal’s regulatory statement. We received feedback that the Code drafting could be improved further, and the cost-benefit analysis clarified to fully consider cost implications associated with amending the FIR and SIR definitions.
- 3.27 The EEA, Transpower, and the University of Auckland all reinforced the need to ensure that the Procurement Plan was updated and came into effect before the proposed Code amendment took effect. The EEA considered the electricity industry should have sufficient notice and opportunity to review any revised technical requirements in the Procurement Plan.
- 3.28 Transpower submitted that the words “...that is sustained until at least 15 minutes...” in the proposed Code SIR definition should be removed to avoid potential confusion with the existing SIR definition in the Procurement Plan.
- 3.29 The University of Auckland submitted that the regulatory statement should be amended to include:
 - (a) the compliance certainty benefits of the Code amendment for the interruptible load sector
 - (b) the revenue measurement implications for BESS and interruptible load providers from changing the trigger definition for SIR provided by load, from ‘a start of contingent event’ trigger to a ‘frequency falls to or below 49.2 Hz’ trigger.
- 3.30 WEL Networks submitted that the following should be addressed alongside the proposed amendments:
 - (a) The proposed FIR and SIR definitions should reference under-frequency events rather than contingent and extended contingent events, since not all contingent events result in an under-frequency event.
 - (b) There should be clear alignment of FIR and SIR trigger points and measurement methodologies to ensure FIR is not pre-empted by SIR. The current settings allow SIR to respond earlier than FIR, which weakens the intended hierarchy between these two ancillary services. This can have negative commercial impacts, especially for higher-value FIR.
 - (c) There needs to be explicit clarification in the Procurement Plan as to whether sustainment durations represent minimum requirements, and whether there are any practical upper bounds on expected delivery duration. Currently the Procurement Plan is unclear on these matters, which is challenging for technologies with fixed-duration capabilities.

- (d) There needs to be clear guidance on restoration expectations, including whether early restoration may be permitted when instructed by the System Operator, and what level of post event recovery and re-availability is reasonably expected. Currently, there is ambiguity in this area, which leaves industry participants uncertain about compliance and potentially disadvantages some technologies.
- (e) Where appropriate there should be technology-specific performance envelopes to ensure the framework remains technology neutral while providing certainty to industry participants.

The Authority's decision

- 3.31 In response to WEL Network's submission, the Authority has decided to amend the proposal consulted on, to clarify that the FIR and SIR definitions relate to contingent events or extended contingent events that cause frequency to fall. The Code drafting changes are shown in blue:

fast instantaneous reserve means ~~instantaneous reserve provided the increase in generation or reduction in demand (in MW) provided no later than 6 seconds, and measured at 6 seconds,~~ after the start of a "Contingent Event" ~~or an "Extended Contingent Event"~~ (both as defined in the **policy statement**) that results in a fall in frequency, where that instantaneous reserve is provided in accordance with the requirements for fast instantaneous reserve set out in the procurement plan and that is sustained until at least 60 seconds after the start of the "Contingent Event" ~~or "Extended Contingent Event"~~.

sustained instantaneous reserve means ~~instantaneous reserve provided the average increase in generation or reduction in demand (in MW) provided by instantaneous reserve during the first 60 seconds~~ after the start of a "Contingent Event" ~~or an "Extended Contingent Event"~~ (both as defined in the **policy statement**) that results in a fall in frequency, where that instantaneous reserve is provided in accordance with the requirements for sustained instantaneous reserve set out in the procurement plan and that is sustained until at least 15 minutes after the start of the "Contingent Event" ~~or "Extended Contingent Event"~~ (unless a new **dispatch instruction** is given before the expiry of that 15 minute period).

- 3.32 The Authority is aware of the need to appropriately sequence the implementation of the Code amendment and changes to the Procurement Plan. We have worked with the System Operator to ensure this alignment exists.
- 3.33 We note Transpower's feedback however, we consider that if we removed that part of the definition, the SIR definition would largely be meaningless in its current form.
- 3.34 We agree with the University of Auckland that the Code amendment will deliver improved compliance certainty for the interruptible load sector. We consider this feedback a useful clarification of the benefit we described in the Code amendment proposal – being a reduction in unnecessary transaction and compliance costs associated with industry participants interpreting and understanding the Code. To this end, the University of Auckland's feedback supports our decision to proceed with the Code amendment.
- 3.35 In respect of the University of Auckland's other feedback, the Authority considers the Code amendment has no revenue measurement implications for BESS and interruptible load providers of SIR. BESS and interruptible load providers of instantaneous reserve are paid an availability fee based on the marginal price for the trading period and the amount of instantaneous reserve dispatched in that trading period, regardless of whether or not there is an under-frequency event in the trading period.
- 3.36 Additionally, there are no changes for SIR provided by interruptible load. An under-frequency event occurs when island frequency has fallen to 49.25Hz or below. Generation is expected

to respond to frequency dynamically when frequency leaves the normal band (49.8Hz – 50.2Hz) while for interruptible load, FIR and SIR are both triggered at 49.2Hz (or another setpoint agreed with the System Operator).

- 3.37 Regarding the submission feedback from WEL Networks that is summarised in paragraphs 3.30(b) to 3.30(e), the Authority considers these matters relate to the Procurement Plan rather than the main body of the Code and are appropriately considered in the first instance by the System Operator.
- 3.38 Therefore, we have referred WEL Networks' feedback to the System Operator. The Authority agrees with the System Operator's response, a summary of which is below. Appendix B contains the System Operator's full response.

Feedback	Response from System Operator
There should be clear alignment of FIR and SIR trigger points and measurement methodologies to ensure FIR is not pre-empted by SIR. The current settings allow SIR to respond earlier than FIR, which weakens the intended hierarchy between these two ancillary services. This can have negative commercial impacts, especially for higher-value FIR.	FIR and SIR are not triggered at different frequencies. For interruptible load, FIR and SIR are both triggered at 49.2Hz (or another setpoint agreed with the System Operator). For generation reserve, the FIR and SIR response begins once frequency leaves the normal band as generators and BESSs can respond dynamically to frequency.
There needs to be explicit clarification in the Procurement Plan as to whether sustainment durations represent minimum requirements, and whether there are any practical upper bounds on expected delivery duration. Currently the Procurement Plan is unclear on these matters, which is challenging for technologies with fixed-duration capabilities.	The 'open ended' restoration time is for interruptible load only. Many loads cannot restore automatically, and some loads must remain off after tripping because of technical limitations. If loads cannot remain off for long durations, they can still offer a FIR product. However, the different reserve products have distinct performance requirements designed to stop frequency falling and to allow the system frequency to recover promptly to within the normal band.
There needs to be clear guidance on restoration expectations, including whether early restoration may be permitted when instructed by the System Operator, and what level of post event recovery and re-availability is reasonably expected. Currently, there is ambiguity around recovery times and readiness for subsequent contingency, which leaves industry participants uncertain about compliance and potentially disadvantages some technologies.	During restoration of instantaneous reserve post an under-frequency event, there are no requirements for the System Operator to manage subsequent events. Instantaneous reserve continues to be scheduled and dispatched by the System Operator during an under-frequency event in accordance with the methodology laid out in the policy statement. Dispatched generation will remain available for further dispatch unless the generation is required as energy. Generators and BESSs have a dynamic response to frequency and are either latched⁹ if frequency fails to recover or respond dynamically if frequency has recovered to within the normal band or close to the normal band. The FIR response from interruptible loads is only sustained for 60 seconds and can be restored automatically without instruction from the System Operator. For SIR, the interruptible load provider must wait until an instruction to restore load has been received from the System Operator before restoring any interruptible load.

⁹ A reserve response that remains fixed at the level triggered by the lowest frequency reached during an event until the frequency has recovered above a set threshold, usually back within the normal band.

	This may happen at any time after the under-frequency event, although the System Operator works to restore loads as soon as possible, ideally within 15 minutes.
Where appropriate there should be technology-specific performance envelopes to ensure the framework remains technology neutral while providing certainty to industry participants.	Performance envelopes were developed for different technologies, including a BESS, as part of the 2025 Procurement Plan update.

FSR-104: Revise two fault ride through exclusions

Proposal

3.39 The Authority proposed to:

- (a) amend clause 8.25B(3) to state that all forms of transmission-connected variable and intermittent generation do not have to comply with clause 8.25B(2) if there is a reduction in the intermittent power source during the six seconds following the commencement of a transmission fault
- (b) delete clause 8.25D(a) so that wind generating stations operating at less than 5% of maximum continuous megawatt (MW) output power would not be subject to fault ride through¹⁰ obligations.

Stakeholder feedback

- 3.40 All stakeholders supported this proposal and agreed with the regulatory statement for the proposal.
- 3.41 The University of Auckland sought clarification on the impact that deleting clause 8.25D(a) may have on partial curtailment and wind-BESS hybrid plant edge cases. They considered that industry participants with these configurations need regulatory certainty about whether fault ride through obligations apply during such operational states. They suggested that a targeted clarification or savings provision in the Code amendment would address this without altering the overall policy intent.
- 3.42 The University of Auckland also submitted that the word 'wind' should be deleted from clause 8.25B(3).

The Authority's decision

- 3.43 After considering submissions, the Authority has decided to proceed with the proposal as consulted on.
- 3.44 In response to the University of Auckland's feedback, the Authority notes the word 'wind' has already been deleted from clause 8.25B(3), meaning no further action is required in relation to this submission point.
- 3.45 With regard to the University of Auckland's feedback on deleting clause 8.25D(a), the Authority considers that no legacy clause or savings provisions are necessary for wind-BESS hybrid plants. This is because currently there are no such plants operating, nor expected to be operating in the near future, that would be affected by the Code amendment.
- 3.46 The Authority notes we are considering how asset owner performance obligations should apply to BESS-hybrid stations, with our aim being to consult with interested parties on this in the first quarter of 2027.

¹⁰ Fault ride through refers to the ability of generating plant, when electrically connected to the power system, to remain stable and electrically connected during transmission faults on the power system.

FSR-105: Clarify who provides information to assess compliance with fault ride through obligations

Proposal

- 3.47 The Authority proposed replacing clause 8.25A(3) with a new clause 8.25AB to reflect the actual arrangements in place to determine compliance with clauses 8.25A(1) and 8.25A(2).
- 3.48 The new clause 8.25AB would set out how the System Operator checked whether a generator could stay connected during faults on the power system and what would happen if compliance was unclear.

Stakeholder feedback

- 3.49 All stakeholders supported this proposal and agreed with the regulatory statement. The feedback received was largely related to clarity of the Code drafting.
- 3.50 The University of Auckland submitted that the Authority should:
- (a) monitor how the embedded generator provisions are applied in the first year, and use regulatory oversight to address any distributor compliance gaps
 - (b) consider a transitional implementation period and evaluate whether distributors have the tools or expertise required to provide the necessary network models
 - (c) commit to monitoring the practical application of the embedded generator provisions in the first 12 months after commencement of the proposed Code amendment, and review any gaps in distributor compliance through the appropriate regulatory oversight mechanism.
- 3.51 Transpower requested an amendment to clause 8.25AB(1) to remove the words “whether each of a generator’s assets, when electrically connected to a network, meets the requirements of clauses 8.25A(1) and 8.25A(2) by reviewing”. Transpower considered this would clarify that the System Operator’s technical assessment of a generator’s power system analysis would not extend to any approval process in relation to the generator’s compliance obligations under clauses 8.25A(1) and 8.25A(2) of the Code.
- 3.52 Nova Energy recommended the addition of a reasonableness condition to the proposed clause 8.25AB.

The Authority’s decision

- 3.53 The Authority has decided to proceed with the proposal as consulted on.
- 3.54 In response to the University of Auckland’s feedback, the Authority considers that as the amendment reflects current practice, transitional provisions, a monitoring regime or an assessment of current modelling capabilities will not be necessary.
- 3.55 In response to Transpower’s feedback, the Authority considers no changes are required to the proposed Code amendment we consulted on. We note clause 8.28(1) requires each asset owner to satisfy the System Operator that each of its assets or configuration of assets complies with the asset owner performance obligations and technical codes applicable to that asset or configuration of assets. We consider the words Transpower proposed be removed are necessary to make clear how an asset owner is to satisfy the System Operator that its asset or configuration of assets meets the requirements of clauses 8.25A(1) and 8.25A(2).

3.56 The Authority considers that Nova's request is already provided for by clause 8.25AB(4) and paragraph 1.4 of the Connected Asset Commissioning, Testing, and Information Standard (CACTIS):

- (a) Clause 8.25AB(4) requires the System Operator and generator to seek to reach agreement on any further power system analysis needed to prove whether the asset meets the requirements of clauses 8.25A(1) and 8.25A(2).
- (b) Paragraph 1.4 of the CACTIS states that, after reviewing information provided by an asset owner, the System Operator may reasonably request additional information or require the asset owner to amend and resubmit documentation if the information is incomplete or does not meet the required standards. The asset owner must comply with the request within the timeframe agreed with the System Operator or if no agreement is reached, within a reasonable timeframe determined by the System Operator.

FSR-106: Clarify obligations related to frequency management and frequency support

Proposal

3.57 The Authority proposed amending clauses 8.17 and 8.19 to clarify what assets are excluded from the obligations to support frequency management in general and during under-frequency events.

Stakeholder feedback

- 3.58 All stakeholders supported this proposal and agreed with the proposal's regulatory statement.
- 3.59 Nova Energy noted that it does not seem plausible for an intermittent generating station to comply with the proposed (and current) requirement to "at a minimum, sustain pre-event output..." when there has been a subsequent post-event reduction in its variable and/or intermittent power source. They suggested that consideration be given to explicit recognition of this, consistent with the proposed clause 8.25B(3) under the FSR-104 Code amendment proposal.
- 3.60 The University of Auckland noted that as the proportion of utility-scale solar photovoltaic generation in the 20–50MW range increased, the cliff-edge compliance effect of the current threshold would affect a growing number of projects. They suggested that a future work programme that reviews the threshold with appropriate industry consultation and modelling of the system security implications would be a valuable complement to the housekeeping work being done under FSR-106.

The Authority's decision

3.61 Following consideration of Nova's feedback, the Authority has decided to amend the proposal consulted on so the variability and intermittency of intermittent generation is taken into account when requiring assets to support frequency management during under-frequency events. We have also clarified the wording that says sustaining pre-event output is a minimum requirement. The Code drafting changes reflecting this are shown in blue:

8.19 Contributions to frequency support in under frequency events

- (1) ~~Subject to subclause (3), each~~ Each North Island generator must ~~at all times~~ ensure that, ~~while electrically connected,~~ its assets, other than any ~~excluded generating stations~~ excluded generating station, contribute to supporting frequency at all times while synchronised by ~~remaining synchronised,~~ ensuring that each of its generating units remain

~~synchronised~~ ~~can~~ and ~~does~~, subject to any variability or intermittency in the generating unit's power source, at a minimum, sustain at least their pre-event output—

...

- (3) Each South Island **generator** must ensure that ~~each of~~ its **assets**, other than ~~excluded generating units~~ ~~any excluded generating station~~, contribute to supporting frequency at all times while synchronised by ensuring that each of its **generating units** remain ~~remains~~ synchronised, and ~~can and do~~, subject to any variability or intermittency in the generating unit's power source, at a minimum, sustain at least their pre-event output—

...

- 3.62 In response to the University of Auckland's feedback, the Authority notes that, effective 1 July 2026, the 30MW excluded generating station threshold was lowered to 10MW.

4 We expect our decision to deliver benefits supporting our statutory objectives

- 4.1 After considering all submissions, the Authority's view is that the six Code amendments support our main statutory objective to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.
- 4.2 We also remain of the view that the benefits of the six Code amendments outweigh the costs, for the reasons set out in our March 2026 consultation paper. We note that submitters largely agreed with our regulatory assessments, with some limited feedback suggesting minor improvements to the FSR-101 and FSR-103 assessments. The Authority has captured and responded to this feedback in our responses to submitter feedback in section 3 of this paper.

5 Next steps

- 5.1 The Code amendments in this decision paper will come into effect on 1 December 2026.

Procurement Plan

- 5.2 The Procurement Plan updates required under the FSR-103 Code amendment will come into effect before the FSR-103 Code amendment. In accordance with clause 7.20(5) of the Code, the System Operator is not consulting on these changes to the Procurement Plan as the Authority has consulted sufficiently on this matter.
- 5.3 Full details of the amended Procurement Plan can be found [here](#).

6 Attachments

- 6.1 The following appendices are attached to this paper:
- **Appendix A** Approved Code amendments
 - **Appendix B** System Operator's full response to WEL Networks' Procurement Plan-related feedback

Appendix A Approved Code amendments

- A.1 This appendix contains the Code changes made for each of the Code amendments the Authority has decided to make in response to submitter feedback and in accordance with the decisions set out in the main body of this document.
- A.2 Code changes are shown as follows:
- (a) text or formatting is red underlined where the consultation paper proposed it be added to the Code
 - (b) deleted text is ~~red strikethrough~~ where the consultation paper proposed it be deleted from the Code.
 - (c) text or formatting is shown in blue underlined where drafting changes were made following consultation and it is to be added to the Code
 - (d) deleted text is in ~~blue strikethrough~~ where drafting changes were made following consultation and it is to be deleted from the Code.

FSR-101

Part 1

Preliminary provisions

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1.1 Interpretation

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~~maximum South Island frequency means the maximum frequency permitted in the South Island, which is 55 Hertz~~

~~over frequency limit means the maximum frequency of 50.5 Hz~~

...

Part 7

System operator

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7.2A System operator to maintain frequency

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(5) During a contingent event in the North Island, the **system operator** must ensure that, for ~~the that island in which the contingent event takes place~~ —

- (a) frequency remains at or above 48 Hertz and at or below 52 Hertz during the contingent event; and
- (b) frequency returns to or above 49.25 Hertz and to or below 51.25-50.75 Hertz within 60 seconds after the contingent event.

~~(5A) During a contingent event in the South Island, the **system operator** must ensure that, for that island—~~

- ~~(a) frequency remains at or above 48 Hertz and at or below 55 Hertz during the contingent event; and~~

- (b) frequency returns to or above 49.25 Hertz and to or below ~~52~~50.75 Hertz within 60 seconds after the contingent event.
- (6) During an extended contingent event in the North Island, the **system operator** must ensure that, for that **island**—
- (a) frequency remains at or above 47 Hertz and at or below 52 Hertz during the extended contingent event; and
 - (b) frequency does not drop to or below 47.1 Hertz for longer than 5 seconds during the extended contingent event; and
 - (c) frequency does not drop to or below 47.3 Hertz for longer than 20 seconds during the extended contingent event; and
 - (d) frequency returns to or above 49.25 Hertz and to or below ~~51.25~~51.2 Hertz within 60 seconds after the extended contingent event.
- (7) During an extended contingent event in the South Island, the **system operator** must ensure that, for that **island**—
- (a) frequency remains at or above 45 Hertz and at or below 55 Hertz during the extended contingent event; and
 - (b) frequency returns to or above 49.25 Hertz and to or below 52 Hertz within 60 seconds after the extended contingent event.

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Part 8

Common quality

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Schedule 8.3

Technical codes

...

Technical Code B – Emergencies

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9 Obligations of generators and ancillary service agents to take independent action

- (1) The following independent action is required of **generators** and **ancillary service agents** during the occurrence of extreme variations of frequency or voltage at the **points of connection** to which their **assets** are connected (such extreme levels of frequency or voltage are deemed to constitute a **grid emergency** and require a fast and independent response from each **generator** and each **ancillary service agent**):
- ...
- (b) when ~~the over frequency limit is reached and~~ the frequency reaches 50.5 Hertz and continues to rise, each **generator** must use reasonable endeavours to take the following immediate independent action to assist in restoring frequency:
 - (i) decrease the energy injection from **electrically connected generating units** if the **generator** is physically capable of decreasing such **injection**;
 - (ii) report to the **system operator** as soon as practicable after taking action in accordance with subparagraph (i):
- ...

Schedule 8.3

Technical codes

...

Technical Code A – Assets

...

5 Specific requirements for generators

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- (2) Each **generator** must ensure that ~~for each of its **generating units** **generating stations** with a **point of connection** on~~ ~~connected to the grid is equipped with,—~~
- (a) ~~if a **generating unit** is equipped with~~ a voltage **control system**, ~~the voltage control system—~~
 - (i) ~~with has~~ a voltage set point that is adjustable over the range of ~~voltage voltages~~ set out in clause 8.23; and
 - (ii) ~~operates continuously in the voltage control mode when **synchronised**; and~~
 - (ab) ~~if a **generating unit** is not equipped with a voltage control system, then the **generating station** must be equipped with a voltage control system that—~~
 - (i) ~~has a voltage set point that is adjustable over the range of voltages set out in clause 8.23; and~~
 - (ii) ~~operates continuously in the voltage control mode when **synchronised**; and~~
 - (b) ~~in order to meet the **asset owner performance obligations**, the **generating station** has either—~~
 - (i) ~~a at least one~~ connection transformer, ~~located at the **generating station's point of connection** on the **grid** or between the **generating station's point of connection** on the **grid** and the **generating units**,~~ with an appropriate range of taps ~~on each transformer~~ together with an on-load tap-changer; or
 - (ii) **assets** to give a dynamic performance at least equivalent to those required by subparagraph (i).

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fast instantaneous reserve means ~~instantaneous reserve provided the increase in generation or reduction in demand (in MW) provided no later than 6 seconds, and measured at 6 seconds, after the start of a “Contingent Event” or an “Extended Contingent Event” (both as defined in the **policy statement**) that results in a fall in frequency, where that~~ instantaneous reserve is provided in accordance with the requirements for fast instantaneous reserve set out in the **procurement plan** and that is sustained until at least 60 seconds after the start of the “Contingent Event” or “Extended Contingent Event”

sustained instantaneous reserve means ~~instantaneous reserve provided the average increase in generation or reduction in demand (in MW) provided by instantaneous reserve during the first 60 seconds after the start of a “Contingent Event” or an “Extended Contingent Event” (both as defined in the **policy statement**) that results in a fall in frequency, where that~~ instantaneous reserve is provided in accordance with the requirements for sustained instantaneous reserve set out in the **procurement plan** and that is sustained ~~for until~~ at least 15 minutes after the start of the “Contingent Event” or “Extended

Contingent Event” (unless a new **dispatch instruction** is given before the expiry of that 15 minute period)

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8.25B Reactive current and active power output

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- (2) Each **generator** must ensure that each of its **generating units** provides **active power** output relative to pre-fault **active power** output at least in proportion to the **grid** voltage at the **grid injection point** for the period of 6 seconds immediately following the clearance of a fault on the **grid** of a type described in clause 8.25A(1).
- (3) Subclause (2) does not apply to ~~a wind an intermittent~~ **generating station** if there has been a reduction in ~~the its variable and/or~~ intermittent ~~wind~~ power source during the 6 seconds following the commencement of the fault.

8.25D Application

Clauses 8.25A and 8.25B do not apply—

- ~~(a) to a wind generating station when it operates at less than 5% of rated MW; or~~
- (b) to any **asset** at an **excluded generation station**.

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FSR-105

8.25A Fault ride through

- (1) Each **generator** must ensure that each of its **assets**, when **electrically connected** to a **network**, is capable of remaining stable and **electrically connected** when the **grid's** lowest **line-to-line** voltage is within the no-trip zone shaded and marked “No-trip zone” in Figure 8.1 (for an **asset** in the North Island) or Figure 8.2 (for an **asset** in the South Island) for the period of 6 seconds immediately following the commencement of a zero impedance three-phase short circuit fault, or an unbalanced short circuit fault, on any part of the **grid** at 110 kV or 220 kV in the **island** in which the **asset** is connected.
- (2) Each **generator** must ensure that each of its **assets**, when **electrically connected** to a **network**, is capable of remaining stable and **electrically connected** when the highest **line-to-line** voltage at Haywards 220 kV ~~bus-busbar~~ (for an **asset** in the North Island) or Benmore 220 kV ~~bus-busbar~~ (for an **asset** in the South Island) is within the no-trip zone shaded and marked “No-trip zone” in Figure 8.3 for the period of 1 second immediately following the commencement of a trip of the **HVDC link**.
- ~~(3) Whether a generator is complying with subclause (2) must be determined using power system analysis that uses—~~
 - ~~(a) study cases provided by the relevant grid owner ; and~~
 - ~~(b) relevant system assumptions provided by the system operator.~~
- (4) A **generator** is not required to comply with subclause (1) in respect of an **asset** in the event of a fault of a type described in subclause (1) if the **asset** becomes isolated from the **grid** as a result of the fault.
- (5) A **generating unit** need not comply with subclause (1) to the extent that it is complying with a **special protection scheme** approved by the **system operator**.

- (6) The absolute **grid** voltage (per unit) shown on the Y axis of Figure 8.1 and Figure 8.2 is the ratio of **grid** lowest **line-to-line** voltage on a **line** to the nominal operating voltage of the **line** (that is, 110 kV or 220 kV).

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8.25AB Assessing fault ride through compliance

- (1) The **system operator** must assess whether each of a **generator's assets**, when **electrically connected** to a **network**, meets the requirements of clauses 8.25A(1) and 8.25A(2) by reviewing the power system analysis the **generator** must undertake in compliance with the fault ride through study obligations in the **connected asset commissioning, testing and information standard**.
- (2) The power system analysis referred to in subclause (1) must use—
- (a) for any **generating station** with a **point of connection** on the **grid**, one or more network models provided by the **system operator**; and
 - (b) subject to subclause (3), for any **embedded generating station**, one or more network models provided by the **system operator** and the **distributor** to whose **distribution network** the **embedded generating station** is directly connected; and
 - (c) relevant system assumptions provided by the **system operator**.
- (3) If there is a material inconsistency between the software type or the configuration of the network models provided by the **system operator** and the software type or the configuration of the network models provided by the **distributor** under subclause (2), the **generator** and the **system operator** must use the software type and the configuration of the network models provided by the **system operator** to the extent of the inconsistency.
- (4) If the **system operator** considers that a **generator's asset** does not meet the requirements of clauses 8.25A(1) and 8.25A(2), the **system operator** and the **generator** must seek to reach agreement on—
- (a) any further power system analysis needed to prove whether the **asset** meets the requirements of clauses 8.25A(1) and 8.25A(2); and
 - (b) any measures needed for the **asset** to meet the requirements of clauses 8.25A(1) and 8.25A(2).

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8.17 Contribution by injections to overall frequency management

- (1) Subject to subclause (2), ~~each~~ **generator** ~~(while synchronised)~~ and the **HVDC owner** must ~~at all times~~ ensure that its **assets**, other than any ~~generating units within an excluded generating station~~, at all times make the maximum possible **injection** contribution—
- (a) ~~to maintain frequency within the normal band;~~ and
 - (b) ~~to restore frequency to the normal band~~ when frequency is outside the normal band.
- (2) Subclause (1) applies—
- (a) to a **generator** only when its **assets** are **synchronised**; and
 - (b) to the **HVDC owner** only when the **HVDC link** is **electrically connected**.
- (3) -Any ~~such~~ contribution ~~made by the assets of a generator or the HVDC owner in accordance with subclause (1)~~ must be assessed against the **technical codes**.

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8.19 Contributions to frequency support in under frequency events

- (1) ~~Subject to subclause (3), each~~ Each North Island **generator** must ~~at all times~~ ensure that, ~~while electrically connected,~~ its **assets**, other than any ~~excluded generating stations~~ **excluded generating station**, contribute to supporting frequency at all times while synchronised by ~~remaining synchronised,~~ ensuring that each of its **generating units** remain synchronised ~~can and does,~~ subject to any variability or intermittency in the generating unit's power source, at a minimum, sustain at least their pre-event output—
 - (a) ~~at all times indefinitely~~ when the frequency is above 47.5 Hertz; and
 - (b) for at least 120 seconds when the frequency is 47.5 Hertz; and
 - (c) for at least 20 seconds when the frequency is 47.3 Hertz; and
 - (d) for at least 5 seconds when the frequency is 47.1 Hertz; and
 - (e) for at least 0.1 seconds when the frequency is 47.0 Hertz; and
 - (f) at any frequencies between those specified in paragraphs (b) to (e), at least for a period of time for times derived by linear interpolation.
- (2) If the **inherent characteristics** and design of a **generator's generating unit** are such that it is reasonably able to operate beyond the above requirements, the **generator** must declare such capabilities in accordance with clause 2(5) of **Technical Code A** of Schedule 8.3.
- (3) Each South Island **generator** must ensure that ~~each of~~ its **assets**, other than ~~excluded generating units~~ **any excluded generating station**, contribute to supporting frequency at all times while synchronised by ensuring that each of its **generating units** remain ~~remains~~ **synchronised**; and ~~can and do,~~ subject to any variability or intermittency in the generating unit's power source, at a minimum, sustain at least their pre-event output—
 - (a) ~~at all times indefinitely~~ when the frequency is at or above 47 Hertz; and
 - (b) for 30 seconds if the frequency falls below 47 Hertz but not below 45 Hertz.

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Appendix B System Operator's full response to WEL Networks' Procurement Plan-related feedback

WEL Networks feedback	Response from System Operator
There should be clear alignment of FIR and SIR trigger points and measurement methodologies to ensure FIR is not pre-empted by SIR. Under the current Procurement Plan methodology, SIR for interruptible load is assessed from a frequency trigger of 49.8 Hz, whereas FIR is triggered at 49.2 Hz meaning that SIR response can occur earlier than FIR. As a consequence, the measured SIR quantity is increased while the incremental FIR response is reduced, not because of limited capability but because the response has already been delivered as SIR. This outcome undermines the intended hierarchy between FIR and SIR and has direct commercial implications, particularly given that FIR is the higher value reserve product. Clarifying where the requirements sit as proposed does not resolve this distortion.	FIR and SIR are not triggered at different frequencies. For interruptible load, FIR and SIR are both triggered at 49.2Hz (or another setpoint agreed with the System Operator). This is an appropriate setpoint as it ensures that loads are not switched off during frequency transients, while still being high enough to respond to under-frequency events. Generator or BESS response is provided via a dynamic (proportional) frequency response, once system frequency moves outside the normal band of 49.8Hz – 50.2Hz. The full provision of reserves by these providers is delivered only when the frequency drops further. The proportional response of generators and BESS is not assessed in the same way as interruptible load offers.
There needs to be explicit clarification in the Procurement Plan as to whether sustainment durations represent minimum requirements, and whether there are any practical upper bounds on expected delivery duration. The requirement that FIR be sustained for “at least” 60 seconds and SIR for “at least” 15 minutes (or longer in some cases), combined with provisions that reserve must not be restored until instructed by the System Operator and that providers must use reasonable endeavours to maintain response beyond the minimum duration, appears to imply an open-ended sustainment obligation. This has significant implications for technologies that can reliably deliver reserve for fixed or pre-configured durations but may not be capable of indefinite sustainment or dynamic operator-driven restoration.	The ‘open ended’ restoration time is for load restoration only. In an under-frequency event, control rooms do not currently have automatic restoration and must phone all interruptible load providers to determine the loads that can be re-dispatched after the event. A number of sites have technical specifications that do not allow them to immediately turn back on. Interruptible load provider offers may or may not be updated to reflect availability during an event. Note: this does not apply to BESS. If loads cannot remain off for long durations, they can still offer a FIR product. However, the different reserve products have distinct performance requirements designed to stop frequency falling and to allow the system frequency to recover promptly to within the normal band.
There needs to be clear guidance on restoration expectations, including whether early restoration may be permitted when instructed by the System Operator, and what level of post-event recovery and re-availability is reasonably expected. There is no explicit clarity on expectations for recovery time or readiness for a subsequent contingency occurring shortly after restoration. This creates uncertainty for participants as to what constitutes compliant performance and risks disadvantaging certain technologies.	During restoration of instantaneous reserve post an under-frequency event, there are no requirements for the System Operator to manage subsequent events. However, there are obligations on the System Operator to dispatch assets to avoid cascade failure of the power system and to maintain frequency in the normal band. So, the System Operator endeavours to restore the power system as soon as possible after an under-frequency event. During the restoration period, a process check is carried out to ensure automatic under-frequency load shedding will provide cover to ensure any subsequent events will not lead to cascade failure. Restoration from an under-frequency event is done in accordance with the methodology laid out in the Policy Statement. In 2016 the post event process was updated to actively seek reserve as part of recovering the power system, to ensure that reserves provide a sustained response in an under-frequency event. This change improved power system operations and the availability of the instantaneous reserve market. Industry participants and the Authority were included in discussions during the process. Previously, the scheduling and dispatch of reserves was suspended during an under-frequency event.

	As instantaneous reserve continues to be scheduled and dispatched by the System Operator following an under-frequency event, any dispatched generation reserve will remain available for further dispatch unless the generation is required as energy during the under-frequency event. Generators and BESS have a dynamic response to frequency and are either latched if frequency fails to recover, or respond dynamically if frequency has recovered to within the normal band or close to the normal band. For interruptible loads providing FIR, the response is only sustained for 60 seconds and can be restored automatically without instruction from the System Operator. For SIR, the interruptible load provider must wait until an instruction to restore load has been received from the System Operator before restoring any interruptible load. Restoration after an under-frequency event is by phone for interruptible load providers. During restoration, interruptible load providers are expected to follow phone restoration advice (effectively a dispatch instruction). This may happen at any time after the under-frequency event, however the control rooms work to restore loads as soon as possible, ideally within 15 minutes. Once the interruptible load provider has been instructed by the System Operator to restore tripped load, an obligation to claim a bona fide and revise offers would arise if the provider was unable to restore or rearm the load. This allows offers (which have not been bona fide out) to reflect actual post-event capability. Compliance with dispatch instructions works as normal once instruction to restore has been given – instantaneous reserve that is offered and dispatched must be delivered in any subsequent under-frequency events. The System Operator is currently working on implementing a previously deferred change to the Procurement Plan that would require interruptible load providers to provide the System Operator with load and arming indications and measurements. The aim of this is to quicken the restoration of reserves and to automate the post event checks in the future.
Where appropriate there should be technology-specific performance envelopes to ensure the framework remains technology neutral while providing certainty to industry participants.	Performance envelopes were developed for different technologies, including BESS, as part of the 2025 Procurement Plan update. Generator performance requirements (including for BESS) are based on the likely response of the generator for the size of the under-frequency event. The likely response is the modelled response based on the standard under-frequency curve. Performance requirements for loads are based on the maximum sustained response over 60 seconds for FIR and the average response over 60 seconds for SIR.